Accufacts Inc.

"Clear Knowledge in the Over Information Age"

Testimony of
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BEFORE THE

COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
SUBCOMMITTEE ON RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS
U.S. HOUSE OF REPRESENTATIVES

HEARING ON

THE SAFETY OF HAZARDOUS LIQUID PIPELINES (PART 2): INTEGRITY MANAGEMENT

JULY 15, 2010

I would like to thank the Committee for the opportunity to comment this morning. My name is Richard B. Kuprewicz, and I am president of Accufacts Inc, but I am here today as a representative of the public. I have over 37 years experience in the energy industry and I have represented numerous parties, within the U.S and internationally, concerning sensitive pipeline matters.

The vast majority of our clients are public citizens, representatives of local city, county, state, or federal governmental agencies, nongovernment organizations, as well as industry, who need highly specialized independent neutral expertise in these critical matters. To cite two specific examples from our extensive client base: Accufacts played a key role for the City of Bellingham, Washington in developing and negotiating both the Bellingham Pipeline Safety Immediate Action Plan and a Long Term Franchise Agreement with Olympic Pipeline defining startup as well as operational, design, and pipeline management process modifications following the 1999 liquid pipeline tragedy. Accufacts also assisted the Lower Colorado River Authority (LCRA) in Austin, Texas in their successful negotiations and efforts with the Department of Justice, Department of Transportation, Environmental Protection Agency, and Longhorn Pipeline Partners LLP obtaining critical design and operational safety enhancements for the 18-inch liquid products Longhorn Pipeline project.

I currently serve as a representative of the public on the Technical Hazardous Liquid Pipeline Safety Standards Committee and have also served as a representative of the public on various PHMSA/OPS working committees related to pipeline control room management efforts, and as an Executive Member and subcommittee member on the committees assisting PHMSA on the Distribution Integrity Management Program ("DIMP") Report development for Congress, and DIMP federal pipeline safety final rulemaking. Congress identified these important pipeline matters in the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES 2006). I also served for approximately seven years on the Washington State Citizens Committee on Pipeline Safety as a public representative, also serving a stint as its chairman. This Governorappointed pipeline safety Advisory Committee is the only one of its kind in the nation and was formed after the Bellingham tragedy.

I was invited today to provide brief comments based on my experiences related to pipeline Integrity Management ("IM"). While my primary focus today will be on liquid transmission pipelines, many of these comments also apply to gas transmission pipelines. My comments today focus on two major IM issues:

- **Changes are needed in reporting IM performance measures**
- **Pipeline corrosion regulations are inadequate**

<u>Changes are needed in reporting IM performance measures</u>

As a result of the Bellingham, Washington liquid pipeline and the Carlsbad, New Mexico gas transmission pipeline ruptures, as well as other pipeline failures, Congress required integrity management for both liquid and gas transmission pipelines affecting High Consequence Areas (HCAs) in an attempt to ensure that pipeline operators had control of their pipeline systems to prudently avoid such terrible tragedies. Before integrity management, with the exception of an initial hydrotest following pipeline construction, pipeline operators were not required to assess or periodically inspect to ensure their pipelines were under the operator's control to avoid failure. Today 44% of approximately 173,000 miles of hazardous liquid pipelines in the U.S., or 76,000 liquid pipeline miles, and approximately 7% of roughly 300,000 miles of natural gas transmission system, or 21,000 gas transmission pipeline miles, fall under the HCA designations captured by minimum federal IM pipeline safety regulations. Under liquid pipeline IM regulation, pipeline segments that could affect HCAs were to complete initial baseline inspections by February 17, 2009. Following these baseline assessments, reassessment intervals are set at five years for liquid pipelines. Thus, liquid pipelines have completed their initial baseline assessments and are now into their first regulated reassessment cycle.

To date, PHMSA's latest website, summarizing liquid pipeline IM repairs from the 2001 through 2008 time period, indicates that approximately 32,000 pipeline repairs have occurred on the 76,000 miles of liquid pipelines that could affect HCAs since IM regulation was incorporated. Of those reported repairs approximately 7,000 were identified as immediate repair conditions; 5,000 as 60-day conditions; and 20,000 as 180-day conditions, respectively.[1] The good news is that somewhere in these 32,000 anomalies there were situations that would have gone to serious failure and releases, so IM is working as **one** intended safety net to address past serious failings or shortcomings in pipeline management and regulatory practices in this country. In addition, for the same time period, PHMSA reports over 35,000 liquid pipeline repairs have also been made in non-HCA areas. As a brief perspective, PHMSA also reports on its website that under gas transmission IM which is substantially different than the liquid IM regulatory approach, approximately 3,000 pipeline repairs have been made for gas pipelines in HCAs. Since pipeline repairs outside of HCAs for gas transmission pipelines are not reported (a very serious shortcoming), it is impossible to independently ascertain if there is a systemic problem on gas transmission systems, especially the type that can transgress into HCAs. Clearly, given the number of pipeline repairs, it is time for Congress to expand the IM requirements to areas beyond the HCAs.

Before discussing a major shortcoming in IM regulations, it is very important to gain a simple understanding about the four specific categories of anomalies and their repair scheduling requirements defined in liquid pipeline IM regulations.[2] These specific categories are: 1) immediate repair conditions, 2) 60-day conditions, 3) 180-day conditions, and 4) other conditions. Time does not permit me to go into great technical detail, but immediate repair conditions are usually serious corrosion or time delayed third party pipeline damage whose time to failure can be quite unpredictable. 60-day conditions are usually associated with time delayed, less severe third party damage, or poor pipeline construction practices that have damaged the bottom of the pipeline and

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[1] See PHMSA liquid pipeline integrity management performance measures at http://primis.phmsa.dot.gov/iim/perfmeasures.htm.
[2] 49CFR§192452(h)(4) *Special requirements for scheduling remediation.*

that have survived an initial placed in service hydrotest pressure test, but can still result in time delayed failure. 180-day conditions are associated with lower corrosion wall loss thresholds (e.g., a wall loss threshold greater than 50% for 180-day conditions versus greater than 80% for immediate repair conditions) or smaller dent time dependent condition threats associated with more predictable time to failure calculations, but also adds indications of possible cracking, some selective corrosion, or gouging which can also fail over time. "Other conditions" is a "fallback" category clearly placing the responsibility on the pipeline operator to be vigilant and deal with any **identified** conditions that could impair the integrity of the pipeline. For the record, to avoid any possible confusion, gas transmission IM regulations have different requirements for scheduling remediation in HCAs, and as previously mentioned, no reporting requirements for anomalies in non-HCAs.

While it is good news and no surprise that over 32,000 anomalies to date have been captured and remediated under IM regulation in the approximately 76,000 miles of liquid transmission pipeline affecting HCAs, more public transparency is required in IM performance data gathering/reporting to assure that this method is thorough, and more important, appropriate. This is especially true as more risk-based performance approaches are applied by pipeline companies in both HCAs and non-HCAs. The Gulf of Mexico offshore release tragedy, if it can teach anything, clearly underscores what can happen when risk-based performance approaches step into the realm of the reckless, and prudent regulation and check and balances don't come into play to prevent such tragedies.

To its credit, PHMSA has greatly improved reporting and pubic access to more information about pipelines on its websites to improve transparency, including IM performance measures. What is critically missing in the area of IM performance measures are presentations of the results by type of repair condition (immediate repair, 60-day, 180-day, other) by kind of threat (e.g., internal corrosion, external corrosion, third party damage, construction, pipe material, etc., actually found at each repair site), by state. Reporting such analysis by state is important as many states assist PHMSA as interagency partners in the implementation of IM programs. Given the past problems uncovered by the Office of the Inspector General associated with poor industry reporting to PHMSA, it is imperative that IM data results be reported in this more detailed and systematic approach to allow independent analysis, verification, and ensure credibility and confidence in IM approaches with the public (including industry analysts, insurers, the media, etc).[3] In today's computer age, additional performance measure detail can occur with little extra effort by the companies and/or PHMSA. Congress should require changes in IM reporting as outlined earlier, and should also require PHMSA to recompile and restate the anomalies repaired to date as I believe critically important insight will be gained by this effort.

Given the wide variation in smart pig capabilities, a more "actually observed" performance reporting format will permit confirmation of the reported findings and verification that the IM processes are effective and in sync with the appropriate threats for each state. Pipeline threats can be markedly different among the states. For example, for various reasons corrosion is a substantial threat for much of the major pipeline infrastructure in Alaska, while third party damage threats should be essentially nonexistent given the highly controlled limited access environment of many of the pipelines, and the low population density in much of that state. Reporting repairs by threat type within a state will allow PHMSA, a state agency, as well as the public, to identify if there are any specific threats related to a certain area, and that an integrity management program is properly matched or failing to prudently address the threats being actually expected or experienced.

PHMSA is also now taking a vital role in inspecting pipeline construction activities that can seriously affect a pipeline's integrity and IM program over its lifecycle. Quite frankly, pipeline construction activities have historically been left on their own in this country in a jurisdictional regulatory no man's land, and I applaud PHMSA, though it may be a serious resource stretch, for now moving forward into this very important

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[3] Office of the Inspector General, "Integrity Threats to Hazardous Liquid Pipelines," Report Number AV-2006-071; date issued: September 18, 2006.

pipeline construction area. Congress should assure that PHMSA has sufficient resources to perform construction inspections without harming other important efforts. Construction related threats should also be reported as part of IM performance measures. For example, recent construction inspections on new pipelines have uncovered serious problems with poor quality (e.g., pipe permanently yielding under the very important initial hydrotest and serious problems with substandard girth welds that join pipe segments).[4] The very grave issue of substandard quality new pipe resulted in PHMSA issuing an Advisory Bulletin to the industry (ADB-09-01). All IM programs obviously should track and report to PHMSA any related new construction introduced integrity threats to assure they have been properly rectified or are under control during the long lifecycle of a pipeline.

Pipeline corrosion regulations are inadequate

In reauthorizing the federal pipeline safety laws, Congress should also take stronger action on reducing the risks that corrosion poses to the integrity of hazardous liquid and gas transmission pipelines. Even with the implementation of integrity management programs, which do not cover all transmission pipeline segments, corrosion, both internal and external, is still the primary cause of liquid transmission pipeline failures in the U.S. and a major cause of gas transmission failures. This is in spite of the many advances made in pipeline corrosion prevention technology since the 1960's. Federal pipeline safety regulations are very clear in this area – corrosion control on a pipeline system is the responsibility of the pipeline operator. Current federal pipeline safety regulations for internal corrosion parrot many international standard weaknesses - an over-reliance on and over-confidence in corrosion inhibitor chemicals and their effectiveness. As the high profile BP Alaska pipeline failures and releases in 2006 attested, inhibitor chemicals are ineffective if the chemicals can't get to the steel pipe because of incomplete internal corrosion and/or maintenance programs.

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[4] See PHMSA workshop on numerous problems found during just 35 inspections of new pipelines under construction at http://www.regulations.gov/search/Regs/home.html#docketDetail?R=PHMSA-2009-0060.

More recently, “PHMSA has found wide variation in operators’ interpretation of how to meet the requirements of pipeline safety regulations in assessing, evaluating and remediating corrosion anomalies.”[5] This raises serious concerns related to how consistent corrosion anomaly evaluations are, especially for external corrosion, and stresses the importance of modifying the reporting of IM performance measures as discussed earlier. We recommend that Congress require PHMSA to effectively deal with this serious cause of transmission pipeline failures in the U.S. It is clear that additional corrosion regulatory standards are required for pipelines both in HCA and non-HCAs (e.g., mandatory use of cleaning pigs, avoid overreliance on corrosion inhibitors), and the problem appears to go well beyond the inspection tools or methods permitted in IM rules. Ironically, smart pig technology has advanced considerably over the past three decades with regard to general corrosion identification, so the problem goes beyond blaming the tools for poor craftsmanship.

I would also caution that the number of high profile failure events related to corrosion seems to underscore that some companies appear to be diluting their corrosion control programs to save money as they overly rely on IM inspections to catch such risks before failure. Miscalls associated with assumed corrosion rates are part of this problem, especially as corrosion rates can significantly change with time. Selective corrosion, the greater corrosion threat on most pipelines, (e.g., microbiologically influenced corrosion, or MIC) have much higher corrosion rates than the general corrosion rates often cited in industry reference standards, and such selective corrosion can cause pipeline failure well before the next five-year IM regulatory reassessment interval for liquid pipelines and the seven-year reassessment interval for gas pipelines. Many would be amazed at just how fast selective corrosion, if not kept under control, can go through half-inch pipe wall, for example. It is incumbent upon the pipeline operator to have corrosion and maintenance programs to assure corrosion is under control in all segments of their pipelines and not just rely on IM inspections. For the record, IM was to serve as one level of safety and never was or is intended to replace the prudent application of internal and external

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[5] See 10/22/08 PHMSA Anomaly Assessment and Repair Workshop at http://primis.phmsa.dot.gov/meeting/MtgHome.mtg?mtg=55.

corrosion programs. I would strongly suggest that Congress investigate and address this important corrosion risk of concern and require PHMSA to make improvements in both liquid and gas transmission corrosion control regulations that are intended to be supplemented by IM. I would especially advise that Congress pay special attention to gas pipelines, especially those capable of putting more tonnage of hydrocarbon into residential neighborhoods in a form that can cause greater destruction than many liquid pipelines. Gas transmission pipelines have yet to complete their baseline assessments, have longer re-inspection intervals, and different special requirements for scheduling remediation than liquid pipelines. Given the shortcomings identified in my testimony, it is too early to address the issue of modifying the reassessment intervals required by Congress for either liquid or gas pipelines. This matter is especially important for gas transmission pipelines, whose IM requirements in many areas are already less stringent, and cover much fewer pipeline miles than that for liquid pipelines.